Assessing the Long-Term Benefits of Appliance Load Control Strategies

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Direct residential appliance load control programs have been widely used by utilities throughout the United States as a peak-shaving demand-side management strategy. In assessing the load impacts and economic benefits of such strategies, the assumption often is tacitly made that any change in demand at the appliance level will directly affect the capacity requirements at the system level. However, in actual long-run operating conditions the impacts of such strategies--and hence their potential economic benefits--depend to a large extent on the system load characteristics and its relationship with the profile of the controlled load. Thus an assessment of the potential long-term impacts of any load control program is inherently a probabilistic phenomenon and must necessary take into account the likely future changes in the system load profile. Based on end use data collected on 185 residential water heaters in Central Maine Power Company's service territory in 1991, this paper presents a general approach to estimating long-run impacts of direct control strategies.

Background

In 1987 Central Maine Power Company launched a residential load control program as a "peak shaving" strategy for reducing demand during the Company's (and/or New England Power Pool's) system peaks and emergencies. By direct control of electric water heater load, the program is expected to ultimately provide nearly 50 megawatts of peak capacity resource. Interruption is achieved through a power line carrier communication system which has the technical potential for cycling other residential and possibly commercial loads. This system also offers the necessary capabilities for a broad range of distribution-level monitoring and control functions that have come to be known as "distribution automation."

The program today has over 13,000 participants served by 80 substations within the Company's service territory. All year-round customers who use electricity for heating water qualify for the program. Direct mail campaigns, coupled with telemarketing efforts, have been used to promote the program. To encourage participation in the program, customers are offered an initial one-time incentive of $25. In addition, participants receive monthly credits of $5.85 during the winter period (December through March) and $2.00 during summer (July and August) toward their electric bills. The program stipulates that water heater loads may be interrupted for up to four hours on non-holiday weekdays during the periods of 7 am to 12 pm and 4 pm to 8 pm and in case of system emergencies. Three timer options, which shut the water heater off for 20, 18 or 16 hours per day, are also available for customers who wish to have their water heaters controlled daily.

This paper discusses the methodology used in a recent study of the long term benefits of this program and presents the results of the analysis. The focus of the analysis is on 1) deriving short-run, point estimates of load impacts (energy as well as demand) and 2) developing a framework for projecting the long-run resource impacts that are likely to result from the observed short-term results.

The Data

The analysis presented in this paper is based on end use data collected on 185 residential water heaters in CMP's service territory from December 1990 to November 1991. The sample frame for the selection of sites was comprised of all customers who had participated in the Program as of July 1990. The primary consideration in the sampling process was that the final sample be representative of the range of energy use for residential water heating within the Company's service territory.

Based on the analysis of end use data previously collected from a small sample of customers, it was found that energy use during the winter months (December through March) averaged 278 kWh per month with a standard deviation of 120 kWh. Given these estimates, it was determined that a sample of 200 water heaters would be required to obtain statistically reliable estimates of water heating demand at a 90% confidence level with a 5 percent margin of error. The formula for calculation of Standard Error was used as the basis for calculation of the sample size.

An additional consideration in sampling was the limitation of the transponder's signal strength. When the distance between the transponder and the receiver exceeds 5 miles, attenuation of the signal increases the probability of errors in the data. Thus, the final selection of cases was based on a two-stage sampling process. First, an initial sample of approximately 500 sites were randomly selected from the population of participants. In the second stage, this initial sample was screened for proximity to substations. Only sites within a 5-mile radius of a substation were retained.

About 350 customers were contacted by CMP's telemarketing staff and invited to participate in the end-use study. As an incentive to promote participation, and as compensation for the inconvenience caused by the study, customers were offered fifty dollars. Two hundred and forty-five customers (70%) volunteered to participate. A combination of technical difficulties in either installing or establishing communication with monitoring devices resulted in considerable delay in completing the installations. By the end of December, two months after the project had begun, 159 sites were successfully equipped with monitoring devices. Given the importance of obtaining data for a complete winter season, it was decided to discontinue installations. The completed installations, together with twenty six sites already in place from a previous monitoring study produced a final sample of 185 sites.

A primary interest in this monitoring study was to obtain load profiles that would ideally represent the "typical" residential customers eligible for participating in the Water Heater Cycling Program. However, in order to make such a generalization, it is necessary to ascertain that the sample is a valid one. A direct method for sample validation consists of gauging the accuracy of the sample by comparing sample estimates to corresponding population values known through other sources. As part of this study, information on major household demographic characteristics and site attributes of the monitored sample were collected through a brief occupant survey. A comparison of these characteristics with the same information collected from CMP's electric water heating customers in the 1989 Residential Energy Survey shows no significant difference between them.

With respect to average annual electricity usage, family size and number of children in the household, the two groups are particularly comparable. The higher percentage of single-family homes and owner-occupied residences in the sample is not surprising because these characteristics are common among customers likely to participate in energy management programs. In addition, based on installation records, the sample also accurately represents the population of program participants. For example, the two groups are essentially identical in terms of water heater tank capacity (41 gallons and 43 gallons, respectively). Mean temperature settings for the water heaters in both groups is 124 degrees fahrenheit. The most common power rating of the bottom water heater element is 4.5 kilowatts in both groups.

Analysis of Short-Term Impacts

Capacity savings, i.e., reductions in diversified demand for water heating during system peak, constitute the primary benefits resulting from this program. An additional benefit of the program is energy savings resulting from the avoided stand-by loss and potential curtailment of usage during the cycling periods. In assessing the magnitude of such impacts the first task is to determine what the diversified demand of the appliance would have been, had there been no control.

Broadly speaking, there are three approaches available for estimating potential impacts of various strategies used in load control programs.[1] First, and perhaps the most conventional technique is load profile comparison or "day matching." Under this approach, appliance load profiles for a "cycled day" are compared to the load shape characteristics of the appliance during a comparable non-cycled day. Program savings are then determined as the difference in usage between the two day types.

The second method, which is a variant of day matching, relies on regression and load shape information from one or more comparable, non-controlled days to predict what the normal load would have been had the control strategy not been implemented. Thus, this approach in effect "reconstructs" the load profiles for the controlled periods. This technique is especially applicable for air conditioner cycling programs, where weather can be used to predict loads during the controlled period. The main advantages of the latter approach is that its data requirements are modest. Also, since it accounts for any difference in weather between the cycled and non-cycled days, it overcomes a major difficulty of the "day matching" method: that of finding a truly comparable non-controlled day.

The third is the "duty cycle" approach, which is based on engineering estimation of how specific cycling strategies affect the natural duty cycle of the appliance under control.[2] Instead of comparing appliance load profiles during cycled and non-cycled days, the "duty cycle" approach relies on a comparison of the duty cycle of the appliance during normal, non-controlled conditions and the maximum duty cycle allowed by the control strategy.

The day matching method was used in this study. As the first step in the analysis, the data were screened for missing records and anomalies. The procedure used in screening the data focused on examining the data for reasonableness without making any judgmental changes in it. The data were, therefore, screened primarily for outages and outliers. No attempt was made to "reconstruct" the missing data by using information from other periods to substitute the missing intervals. All 15-minute readings greater than the water heater's expected total connected load were treated as outliers and dropped from the analysis database. Attrition in the data was generally low, ranging from 10% in January 1991 to about 25% in October 1991.

Seasonal end use load curves for the average weekday are shown in Figures 1 and 2. They reflect the weighted average monthly load profiles, and are derived from observed historical (10-year) monthly peak probabilities as follows: Winter, 70% January and 30% December; Summer: 60% July and 40% August.

Predictably, there is little seasonal variation in usage patterns. In nearly every month the maximum diversified demand for water heating occurs between the hours of 7:00 and 8:00 a.m. The maximum diversified demand observed during the evening usually occurs between the hours of 7:00 and 8:00 p.m. On weekends a very similar pattern is observed, with the exception that the morning peak occurs about two hours later and extends over a longer period. Minor variations in the timing of usage not withstanding, the total daily usage is considerably lower during the summer months. The monitored water heaters exhibit a relatively high load factor (53% and 57% during the winter and summer periods respectively), which is consistent with nondiscretionary residential end uses.

The effects of controlling the load on a typical winter weekday, when the probability of a system peak is highest, can be seen in Figure 3. The observed residual load during the control period is due to communication problems that prevented the interruption signal from reaching

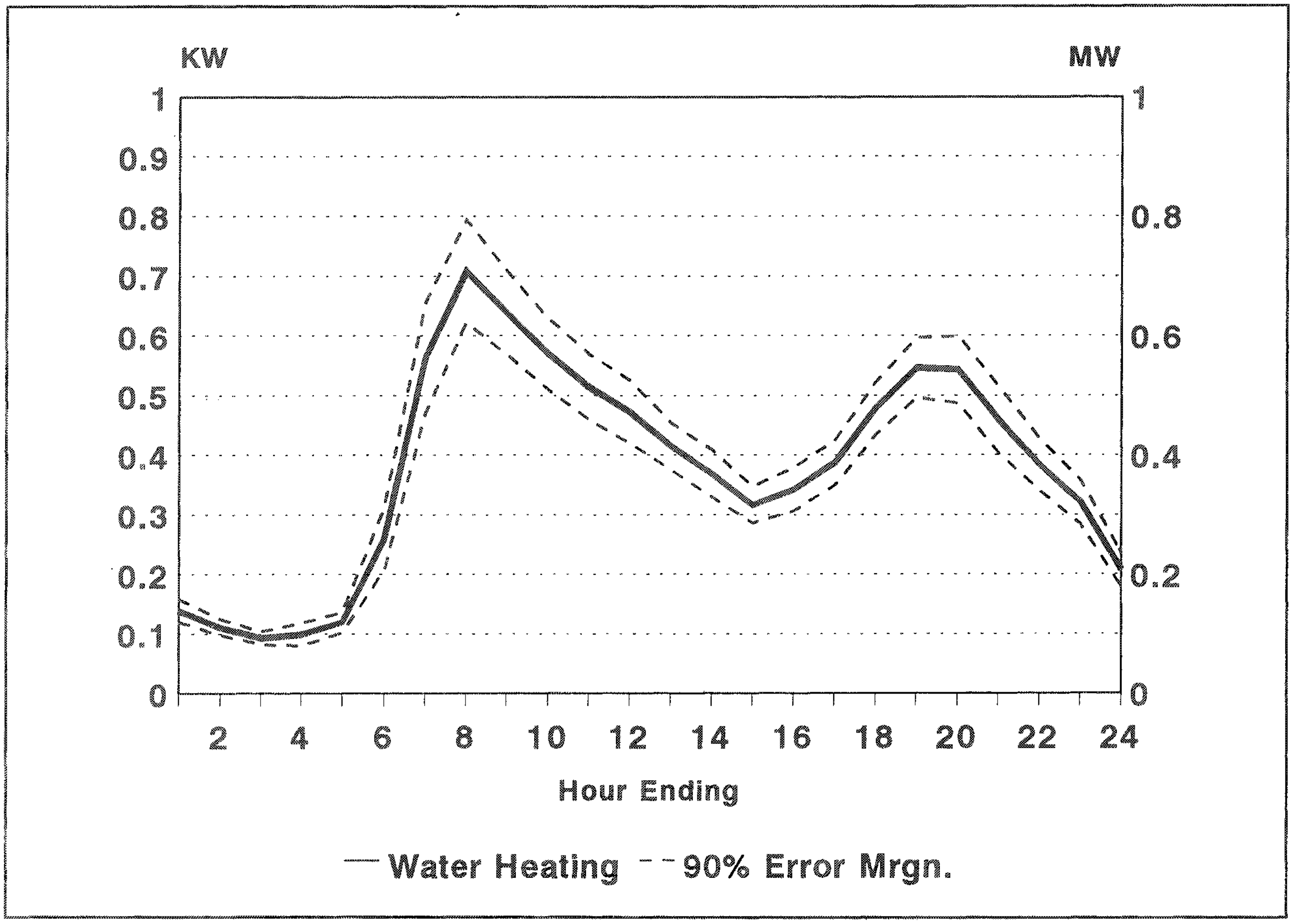

Figure 1. Water Heating Load Profile - Typical Winter Day

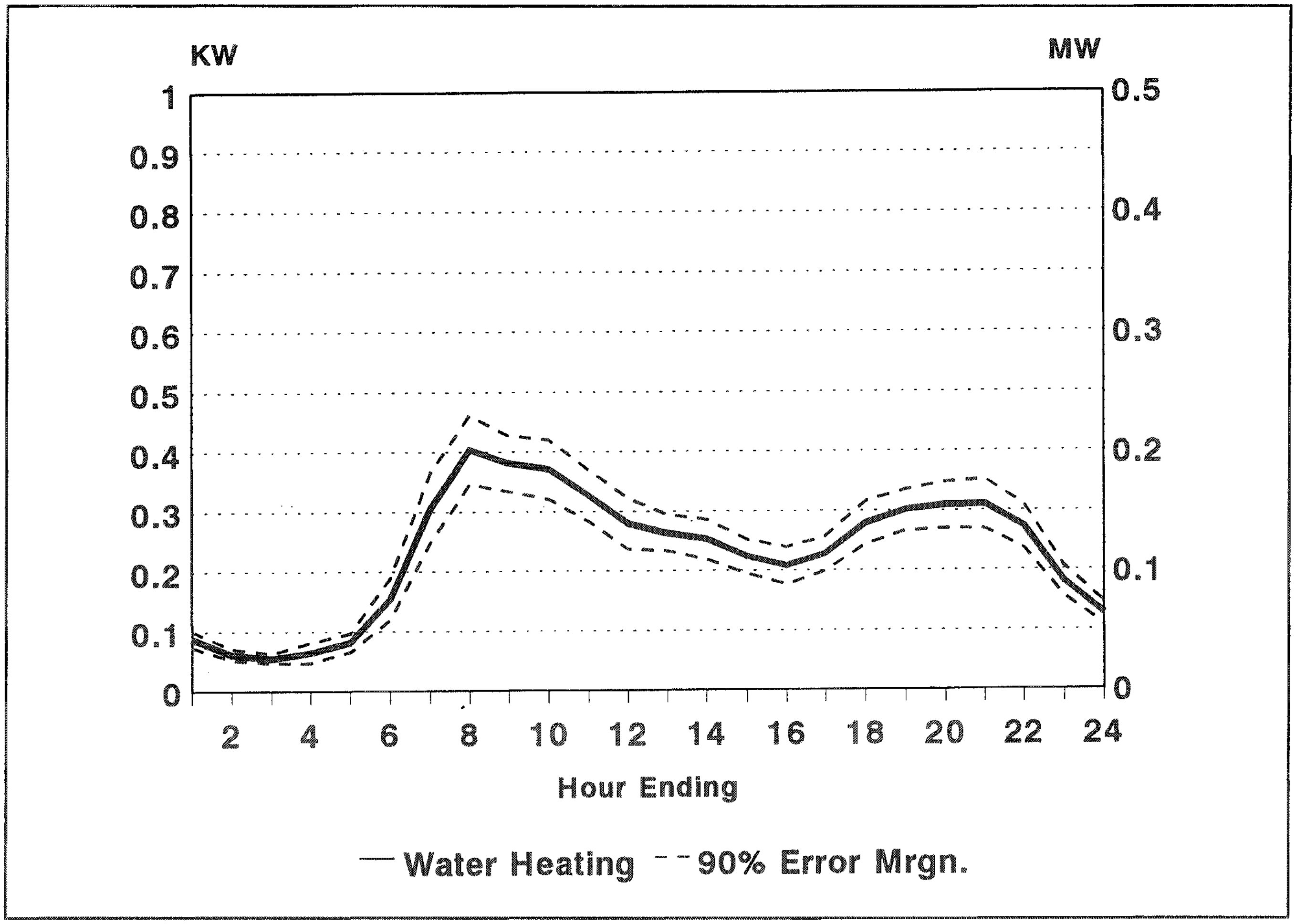

Figure 2. Water Heating Load Profile - Typical Summer Day

some of the control units. The problem has been investigated and corrected. In addition to demand impacts, the findings also suggest that, compared to the average weekday, overall energy use for water heating was lower during control days. The lower average usage in these days is partially explained by the avoided standby losses during the periods when the load is interrupted. The observed difference in usage, however, is somewhat higher than what can reasonably be expected to result from avoided standby loss alone. Changes in water use behavior resulting in hot water conservation during control days appear as the most likely explanation for the observed phenomenon.

Assessment of Long-Term System Impacts

In assessing the effects of load management programs, the assumption is sometimes made that any change in demand at the end use level will directly affect the system's peak demand. However, the value of savings achievable through an appliance load control program is primarily a function of not only the magnitude, but also the timing of the targeted load. In other words, it is the relationship between the appliance and the system load profiles that determine the level of potential savings. The foregoing assumption is not altogether unreasonable when the focus is on the very short-run (annual) impacts. In the long-run, however, the system load profile does not remain constant and hence, strictly speaking, the assumption is no longer valid.

The present analysis, therefore, does not rely on point estimates of diversified demand at the time of system peak. Rather, it adopts a probabilistic approach that explicitly accounts for variations in the system load profile in the long-run. Under this approach, the load impact of the program is measured in terms of the "expected value" of diversified demand at the time of system peak. For each season, this "expected value" is defined as the sum

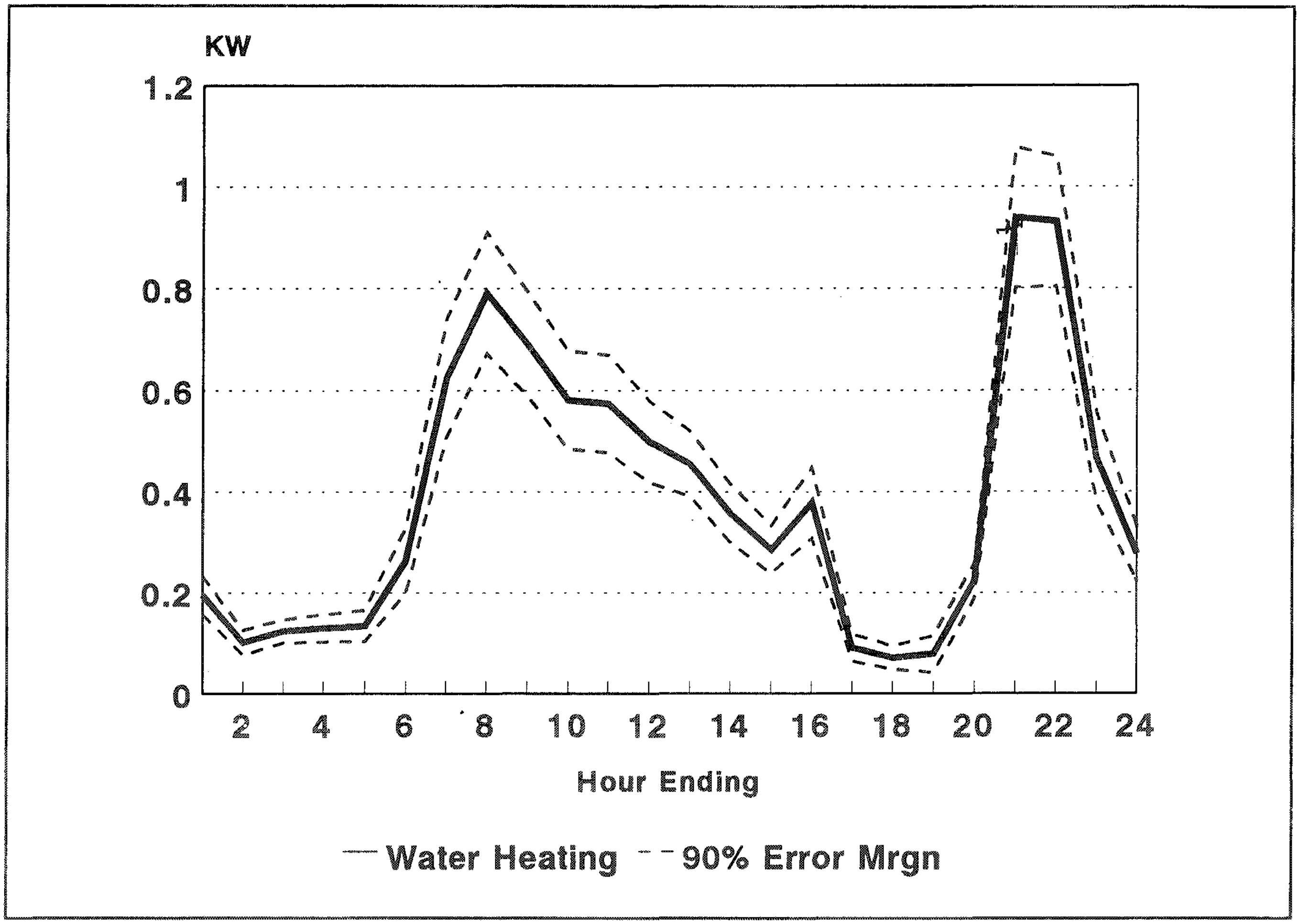

Figure 3. Water Heating Load Profile - Winter Cycled Weekday

of the products of hourly diversified demand and long-run probability of system peak during that hour; analytically:

$$E.V.\ kw\ Impact = \sum (D_i\ x\ P_i)\ x\ P_j$$

where, D_i is diversified demand during period i and P_i denotes historical probability of system peak during the period i. For the purposes of this analysis, system peak probabilities are based on hourly peak frequencies in each weekday of each month during the past ten years. The term P_j represents other uncertainties associated with the realization of demand savings such as signal failure discussed previously.

It is also important to note that this formulation of the expected value of demand savings presupposes that an unrestricted number of cycling days are available to the utility. The provisions of the particular program under study does allow cycling under all system emergency conditions. Clearly, where cycling days are limited, a more complex formulation of the expected value term will be needed to account for such restrictions. Such formulation would take into account the conditional probability that the cycling would actually take place on any given day.

The 10-year average system load profiles, the hourly peak probabilities and seasonal diversified demand for water heating are shown in Figures 4 and 5. Based on the long-run hourly probabilities of system peak, the expected value of per unit load impacts resulting from the program during a typical weekday are estimated at .51 kW in winter, 0.3 kW during summer periods.

Estimation of Energy Savings

Broadly speaking, capacity savings resulting from demand reductions during peak periods constitute the most significant benefits of direct load control programs. These

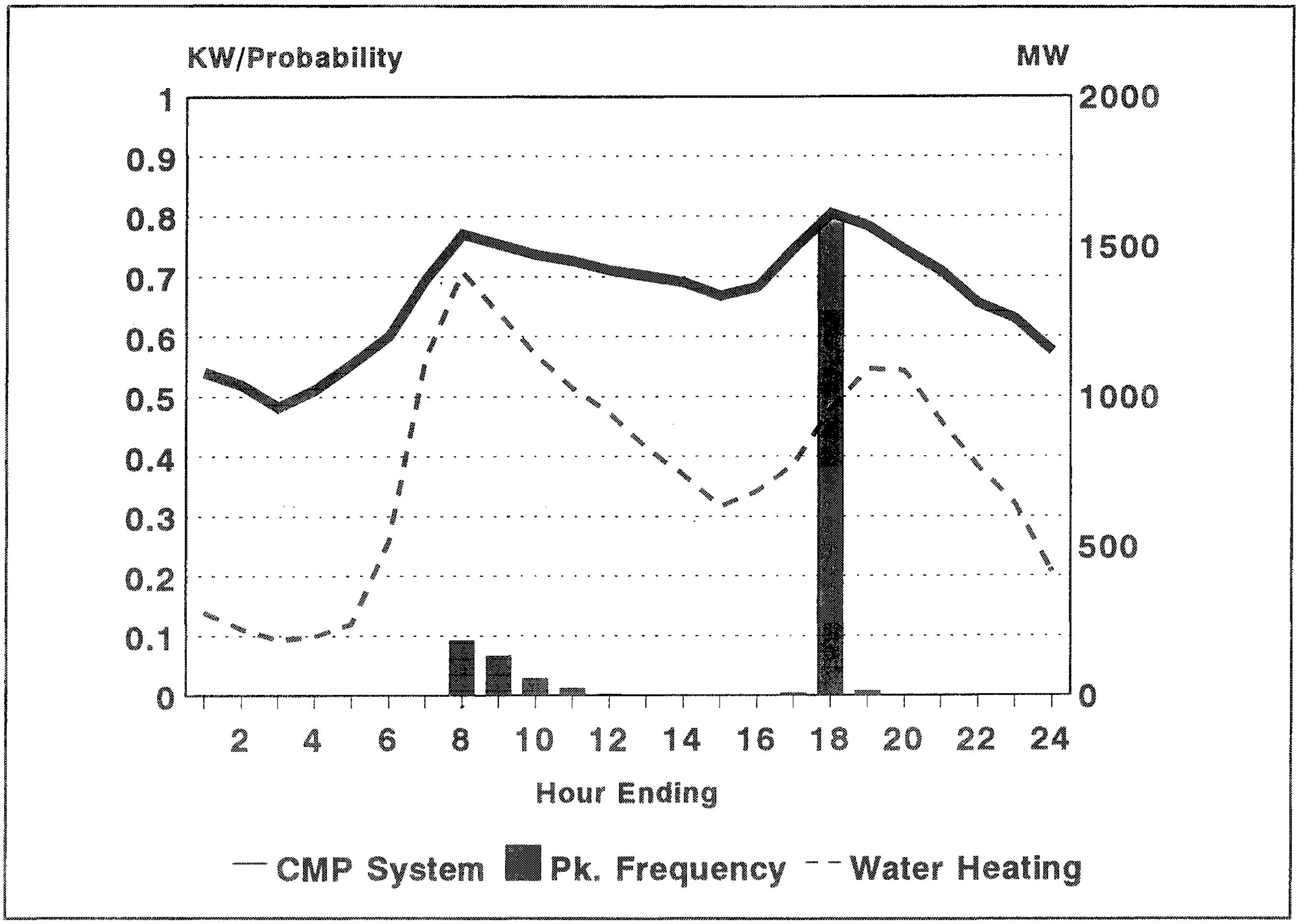

Figure 4. CMP System & Water Heating Load Profiles - Typical Winter Peak Period

programs, however, can produce energy savings that are often ignored. The energy benefits can result from two sources. First, there are the reductions in usage resulting from avoided standby losses and changes in usage behavior. Second, and as important, are the benefits related to marginal energy costs and arise from shifting energy from high-cost periods to lower cost ones.

The value of energy savings resulting from the program was estimated using the "Load Control Model", a component of the algorithm developed for the CMP's Load Management System. The underlying concept of this model is that the energy curtailed in one period creates a "debt" which has to be paid back at a later time and that the amount of this "debt" is primarily a function of the control time. The model is used for computing the maximum number of loads to be shed in each period and determining the optimal control schedule. Given the profile of the controlled load, specific control window(s), and the desired duration of each control period, the model can simulate impacts on the system load curve resulting from any number of control points.[3]

For each season, the energy benefits of the program were estimated by first using the Load Control Model to measure the change in hourly energy use, and then applying the hourly marginal energy costs to determine their value. Using kW_i to designate load at time period i, and letting MC denote marginal energy cost, the value of energy savings (ES) over period T is given by:

$$ES = \sum_{i=1}^{T} (kW_i \times MC_i)_{Before} - \sum_{i=1}^{T} (kW_i \times MC_i)_{After}$$

A final consideration in assessing the impacts of a direct load control strategy is the technical constraints that might affect the system's use. Of particular interest for strategies that shift energy from on-peak periods to off-peak periods

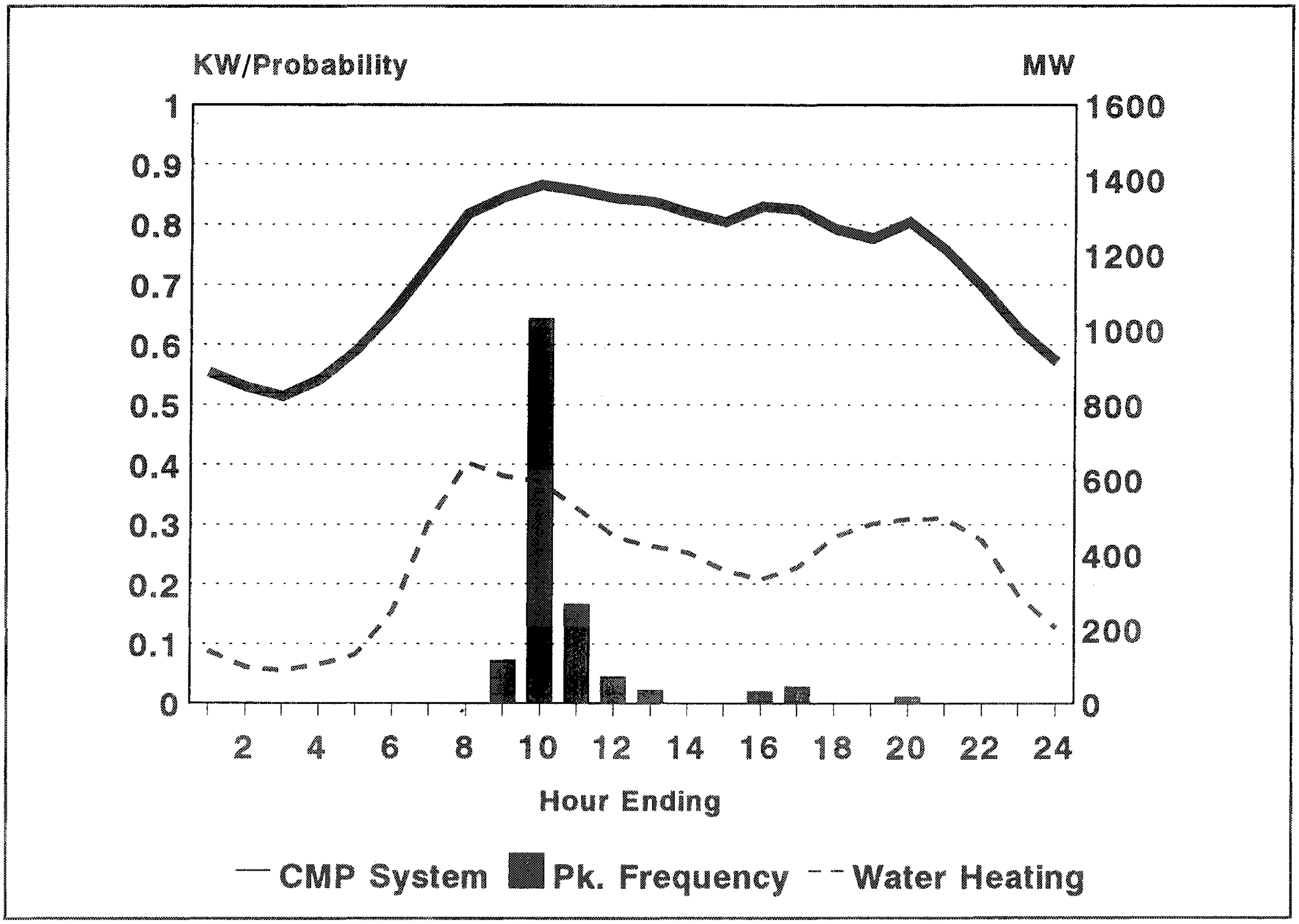

Figure 5. CMP System & Water Heating Load Profiles - Typical Summer Peak Period

is the rate at which the shifted energy must be "paid back" since it may plausibly create another peak. These impacts were estimated by accumulating the energy debt incurred during the interruption period and defining the payback profile with a time constant. As shown in Figure 6, the entire water heater load under program control can be shed and paid back smoothly in this case.

Summary and Conclusions

Load control programs are extensive undertakings that usually involve considerable investment on the part of utilities. Assessment of long-term impacts of these programs is a complex and requires an analysis of uncertainties regarding the operation of the program, technical reliability and potential market penetration. This paper has addressed a specific analytic issue concerning the timing of control strategies and how it relates to the system load characteristics. It was demonstrated that relying on short-run point estimates of load impacts could lead to inaccurate estimates of long-term program effects. In the particular case analyzed, it was found that a static approach would have understated the long-run impacts in the winter months and overstated the summer load impacts.

Endnotes

1. A load control "strategy" refers to a specific plan or schedule to modify the operation of one or more end use by limiting or interrupting the duty cycle of an appliance. A discussion of various load control strategies is found in EPRI. *Control Strategies for Load Management, EPRI EM-3882, July 1985.*

2. For a complete description of the technique see EPRI. *Impact of Direct Load Control Programs: A Duty-Cycle Approach.* Volumes 1&2, EPRI CU-7028, December 1990.

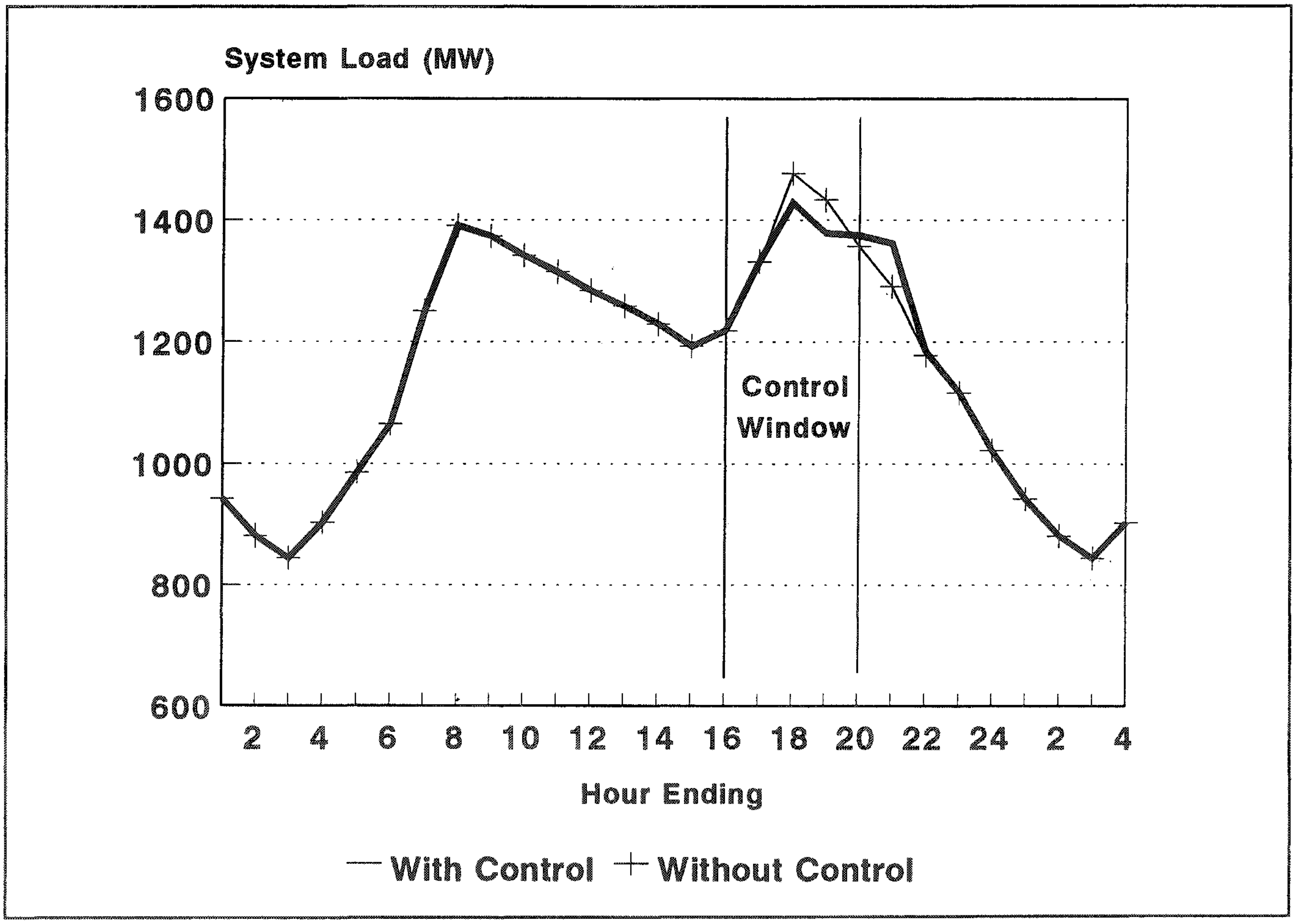

Figure 6. Potential Impact of 100,000 Controlled Units on CMP's System

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3. This model is part of the Load Management System algorithm developed for CMP by ESCA, a Distribution Automation Systems vendor in Bellevue, Washington.